

Hydrodynamics of Oil and Gas



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Preface

There has long been interest in the flow of fluids through permeable aquifers. Stratigraphic trapping of oil and gas by permeability changes in an aquifer and the amounts of hydrocarbons so trapped are major concerns to the oil industry. The variations of aquifer width and geometry and of the positions in an aquifer where hydrocarbons can be trapped by hydrodynamic forces are intimately intertwined in determining the shape, and thus the volume, of hydrocarbons.

Perhaps the seminal work in this area is reflected by King Hubbert's massive review paper "Entrapment of Petroleum under Hydrodynamic Conditions" (*Am. Assoc. Pet. Geol. Bull.* 37(8), 1954–2026, 1953), in which a wide variety of effects, such as capillarity, buoyancy, surface tension, and salinity of water, are incorporated as basic factors influencing the positioning and shaping of hydrocarbon masses in hydrodynamically active aquifers. In those days, while the basic physics could readily be appreciated, development of a detailed quantitative understanding of the interplay of the various factors in controlling or modulating hydrodynamic shapes was severely limited by computer abilities. Indeed, Hubbert actually constructed and photographed physical models, using alcohol and water, to illustrate basic concepts. It is difficult to obtain an appreciation of the behavior of flow geometries from such experiments when all factors are permitted to vary simultaneously. Such an understanding is rapidly becoming of paramount necessity as the petroleum industry struggles to diminish the risk factor in exploring for oil in the last decade of this century.

The point is that, when found (mostly serendipitously), stratigraphic reservoirs are, on a one-to-one basis, as prolific as the more easily identified structural reservoirs. However, using current technology it is extremely difficult to identify stratigraphic trapping of hydrocarbons without actually drilling to see if hydrocarbons are present, and drilling

is an expensive operation. In addition, the positioning of hydrocarbons in a structural trap is, of itself, also modified by hydrodynamic driving forces, as is the access of hydrocarbons to the putative structural trap along a connecting thoroughfare. Thus, structure, stratigraphy, and permeability, by virtue of their intertwined evolution as a sedimentary basin evolves, are all connected in their impact on the migration and hydrodynamic trapping of hydrocarbons.

The advent of high-speed computers capable of handling a wide variety of nonlinear problems has meant that a reevaluation of the hydrodynamic effects on flow patterns can be handled very quickly in a workman-like fashion in a wide variety of situations. Thus, a generic "feel" for the resolution, sensitivity, uniqueness, and precision of understanding of particular regimes can be achieved rather readily.

The purpose of this book is to provide a compendium of behaviors under a variety of conditions so that an appreciation of the interesting patterns of behavior is collected in one place.

The understanding of the structure of hydrodynamic flow patterns and their influence on hydrocarbon behaviors is far from being fully developed. The impact of time-dependent effects (e.g., permeability changes by compaction, fracturing, cementation, or dissolution) on the fundamental properties of the aquifer and the basic response patterns to variable hydrodynamic flow or to oil and/or gas masses being added to (or subtracted from) the total mass budget in an aquifer, etc., have hardly been explored. Equally, solubility effects, temperature and pressure dependence of surface tension, miscibility, hydrocarbon kinetic evolution from oil to gas while in the aquifer, and a wide variety of related phenomena (e.g., episodic fracturing and resealing of capped aquifers) would seem to be worthy of a more detailed treatment than has so far been their lot.

Aware of these limitations, and also of our own abilities, we consider it appropriate to record here the variety of steady-state shapes that are permissible, and the conditions under which they obtain, so that an appreciation can be gleaned of the complexity of behaviors available.

This book is intended both for practioners in the oil industry who are actively involved in the search for subtle stratigraphic traps and for those entering the field, either as students or as full-fledged professionals.

We have tried to develop systematically the subject of hydrodynamic shaping starting with the conditions and assumptions of Hubbert. These conditions are then systematically weakened and generalized throughout the book as more involved patterns of development, more closely mimicking reality, are discussed. At each level of new development in each chapter we provide as an underpinning a short theoretical development

before presenting case histories and examples. The reader interested in obtaining a quick overview of the importance of particular factors can skim through the pictorial representations without first being forced to examine a detailed quantitative development. The reader more interested in the progressive development of the subject *per se* can, on the other hand, read the quantitative development sections and bypass the case histories. The reader interested in an integrated development should, of course, read from cover to cover.

We will have succeeded in our purpose if others can develop the quantitative aspects of hydrodynamic impact to levels significantly beyond the level herein. Suggestions for such developments are recorded in the last chapter.

The results we report would not have been possible without a considerable amount of help and suggestions from many sources. Discussions and collaboration with Zhiyong He on the early phases of this work were crucial, as was the insistence of Mike Zeitlin, Christian Hermanrud, and other industrial contacts that the hydrodynamic impact on oil accumulations needed to be reviewed. We are grateful for scientific and financial support from the Industrial Associates of the Basin Analysis Group at the University of South Carolina. These Associates are Texaco, Oryx Energy, Phillips Petroleum, Conoco, BP, Chevron, Saga Petroleum, Statoil, Unocal, Marathon, and Arco. Support from the Danish Research Academy and the Danish Research Council is also gratefully acknowledged.

We thank our secretary, Donna Black, who had the task of converting our scrawl into type, and Yuan-Yuan Li, who had the thankless task of producing a great fraction of the figures using the Hydrodynamics Code given in the Appendix.

This venture would not have been possible without the support of friends and families who were infinitely forbearing during the long months it took to write this book.

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Introduction

1.1. General Considerations

Two dominant factors determine that hydrodynamic forces are of paramount importance in influencing the location, shape, and amount of hydrocarbons in permeable aquifers and reservoirs. On the one hand, oil has a specific gravity of around $0.8\text{--}0.9\text{ g/cm}^3$, while subsurface waters range in specific gravity from around 1 g/cm^3 to about 1.3 g/cm^3 for hypersaline saturation conditions. Thus, there is a vertical buoyancy drive on oil of around $0.1\text{ to }0.5\text{ g/cm}^3$, depending on conditions. For gas, with a density at production of around $0.1\text{--}0.3\text{ g/cm}^3$, the equivalent buoyancy drive is about $0.7\text{--}1.2\text{ g/cm}^3$. Thus, hydrocarbons have an innate tendency to seek out structural highs if flow conditions and flow pathways exist.

On the other hand, the deposition, and later compaction, of sediments in a basin provides a major water flow throughout the basin's geologic evolution. For example, sediments deposited with 50% porosity and then compacted to a typical reservoir porosity of, say, 10% have decreased their depositional thickness by a factor of 1.8 with the loss of 80% of pore water. Since the pore water originally made up 50% of the sediment thickness, this fact implies that the water lost corresponds to 40% of the rock thickness. For a 15,000-ft column of rock, all at 10% porosity, the implication is that 12,000 columnar feet of water have been "lost." Clearly, the subsurface flow of water in sedimentary basins is a large factor dominating the evolution of the basin on a geologic time scale.

Thus, as hydrocarbons are produced in a basin, they are subject to both an intrinsic buoyancy drive and a significant hydrodynamic drive. In order to assess the pathways of hydrocarbon migration and accumulation, it is essential that the interaction of buoyant hydrocarbons with hydrodynamic forces be examined under as wide a swath of conditions as possible. In this way we can build up an understanding of the overall picture

of evolution of hydrocarbons from source to reservoir and of the subsurface conditions which aid or deter the migration.

While buoyancy and flow predominantly control the evolution of hydrocarbon migration, they have to be encapsulated within the geometric and physical frameworks that govern subsurface phenomena. Thus, the influence of permeability—its spatial and temporal variations—plays a marked role in discriminating viable flow paths from nonviable modes of transport. The variable width and variable shape of aquifer pathways, both spatially and temporally, also control the allowed locations of hydrocarbon accumulations. The variability of hydrodynamic flow and the ability of water to take gas and oil into solution, and so convect hydrocarbons toward unanticipated pathways and accumulation sites, represent another aspect requiring investigation. In addition, the leakage of an aquifer, the variability of grain sizes influencing capillary pressure effects, the precipitation (or dissolution) of minerals decreasing (increasing) the permeability, the temperature dependence of solubilities and surface tensions, and the increase in oil density with time, lowering the buoyancy by solution of the light miscible components of the oil, all have roles to play in influencing the behavior of hydrocarbon transport.

Addition of oil to an already existing hydrocarbon accumulation changes the hydrodynamic forces acting on the oil, thereby influencing the accumulation amount and also impacting the sites of allowed accumulation.

Some of these factors are undoubtedly of minor importance in relation to others that have a more pervasively rugged control on the hydrocarbon behavior. Investigation of dynamic ranges of conditions under which particular factors make their presence felt is one of the major concerns throughout this book.

1.2. Historical Perspective

Hubbert (1953) has noted that the basic acceptance of hydrodynamic flow as a dominant player in the siting of hydrocarbon accumulations had a long and checkered career for the first 80 to 100 years after oil was discovered by Drake in 1859 at Titusville, Pennsylvania. While there had been sporadic attempts to include the influence of the flow of subsurface water prior to the early 1950s, these attempts often waxed and waned with the polemic vigor of the proponents and opponents of the idea. By the early 1950s two major factors firmly entrenched the idea of hydrody-

namics as a major influencing factor. First, Tiratsoo (1952) published a text in which hydraulic activity was regarded as the *sine qua non* in ascertaining hydrocarbon migration pathways and accumulation sites in the petroleum geology arena. Second, Hubbert (1953) published a massive review paper detailing 12 years' involvement (Hubbert, 1940) with the basic problem and exemplifying, by both case histories and laboratory experiments, the basic patterns of behavior impressed on mobile hydrocarbons as a consequence of hydrodynamic flow. In addition, Hubbert (1953) also spelled out a variety of basic factors influencing hydrocarbon flow and provided a fundamental quantitative development for examining the relevant factors, as well as estimates of the size and scale of various factors. A short, but fascinating, account of the early years of development of the hydrodynamic concept is also contained in Hubbert's review paper.

Since that time, there has been a steady and significant improvement in our understanding of hydrodynamic control on hydrocarbon motion. The ability to identify from field observations the likelihood that hydrodynamic action is, or was, active has been examined by Dahlberg (1982), using Hubbert's (1953) paper as a basis from which to build practical rules of thumb. Also, Berg (1975) and Davis (1987) have more recently reinterpreted the basic physics of hydraulic impact on hydrocarbon evolution in interesting manners while remaining within the basic framework of the overriding assumptions set down by Hubbert (1953) governing thin oil stringers. However, as we shall see in Chapter 2, even within the restrictive assumptions of the thin oil stringer approximation, there are degrees of indeterminacy in assessments of the length of an oil stringer.

1.3. Fundamental Rules

1.3.1. Darcy's Law

Darcy (1856) showed experimentally that the velocity, v , of a fluid flowing through a stationary porous medium is proportional to the applied pressure gradient, ∇p , and inversely proportional to the viscosity, μ , of the fluid, so that

$$v = - \frac{\kappa}{\mu} \nabla p. \quad (1.1)$$

The proportionality factor, κ , is the permeability of the porous medium. Note that Eq. (1.1) is an equation of motion for the fluid, thereby replacing Newton's equations of motions.

Darcy's law refers specifically to the applied pressure gradient. In terms of subsurface fluid pressures with a total fluid pressure, p_{tot} , and a fluid pressure p_e in excess of hydrostatic, we have

$$\nabla p_{\text{total}} = \nabla p_e + \rho_w g \hat{z} \quad (1.2)$$

where ρ_w is water density, and \hat{z} is a unit vector in the direction of gravity, of strength g . The relevant pressure in Eq. (1.1) is the excess pressure, p_e .

Darcy's law is often written in terms of an equivalent hydraulic head, H :

$$\mathbf{v} = - \frac{\kappa \rho g}{\mu} \nabla H \equiv - K \nabla H \quad (1.3)$$

where $K \equiv \kappa \rho g / \mu$ is the hydraulic conductivity. The form (1.3) is often used in applications to groundwater flow. Throughout this book, we use the excess pressure formalism because this formalism makes it easier to visualize some important concepts.

Darcy's law operates only under conditions where the spacing, b , between solid matrix particles is much smaller than any other scale of concern in the fluid flow (Scheidegger, 1960; de Wiest, 1969; Bear, 1972). In addition the permeability, κ , depends on both the lithology type and the porosity, ϕ , or void ratio, $V [\equiv \phi / (1 - \phi)]$, of the rock in question. For instance, Dutta (1987) has shown that for Gulf Coast shales and clays a good representation is

$$\kappa = k_0 V^m \quad (1.4)$$

with $m \approx 5$ and $k_0 \approx 3.4 \mu\text{D}$ ($1 \text{ D} \equiv 10^{-8} \text{ cm}^2$) (Fig. 1.1).

Empirically, it appears that a power law representation of permeability and void ratio of the form (1.4) describes a considerable variety of rock types, but the parameters k_0 and m vary significantly, with m typically in the range 3 ± 3 and k_0 varying from microdarcies for shales and clays to darcies for clean sands and gravels. As we shall see later, this massive change in permeability (by factors of order 10^6) between shales and sands causes some interesting behaviors.

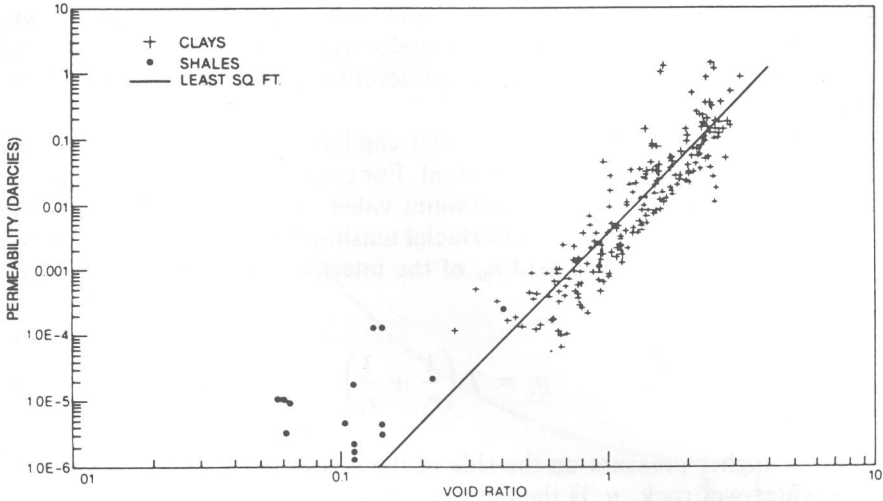


Figure 1.1. Permeability versus void ratio, $\phi/(1 - \phi)$, of U.S. Gulf Coast clays and shales (after Dutta, 1987).

1.3.2. Surface Tension and Capillary Pressure

1.3.2.1. Surface Tension

At the interface between two dissimilar fluids (oil and water, say), there is a surface tension keeping the two fluids in separate phases (Laplace, 1789).

For a common radius of contact, r , between the two fluids, the equivalent discontinuity in surface pressure is

$$\Delta p_{s.t.} = 2T/r \quad (1.5)$$

where T is the surface tension. For oil and water the surface tension at 20°C is around 35 dyn/cm and decreases as the temperature increases. The surface tension is composition specific, being higher for thick heavy crude oils and also higher for hypersaline waters replacing fresh water.

1.3.2.2. Capillary Pressure

If a volume of oil is injected into a water-saturated rock, there is a pressure difference p_c across the interface between the oil and the water. If the rock is preferentially wet by water with respect to oil, p_c will be

positive so that the pressure inside the oil will be greater by p_c than that inside the water; if the rock is preferentially wet by oil, p_c will be negative. Except in rare cases, the rocks are preferentially wet by water (p_c positive) (Fig. 1.2).

The oil volume will adjust so that capillary energy, p_c/ρ_o , will be a minimum, where ρ_o is the density of oil. For constant ρ_o , the configuration must be such that p_c is at its minimum value. The pressure p_c between two nonmiscible fluids whose interfacial tension is T is related to the principal radii of curvature, r_1 and r_2 , of the interface by Plateau's equation (Shorthose, 1936):

$$p_c = T \left(\frac{1}{r_1} + \frac{1}{r_2} \right) \quad (1.6)$$

with the higher pressure on the side of the center of sharpest curvature. In a water-wet rock, p_c is then at a minimum when the oil occupies the largest accessible voids.

If the rock is wet by oil, the capillary pressure p_c would be negative, and for p_c/ρ_o to be a minimum would require that oil be in the smallest accessible voids (Fig. 1.3).

The pressure p_c is the minimum possible value of the capillary pressure, the initial displacement pressure, obtained when oil is injected into a water-saturated rock, as given by the equation

$$p_c = \frac{CT \cos \alpha}{d} \quad (1.7)$$

where C is a dimensionless factor of proportionality, α is the contact angle in the water phase that the oil–water interface makes with the solid boundary, and d is the mean grain diameter (Hubbert, 1953).

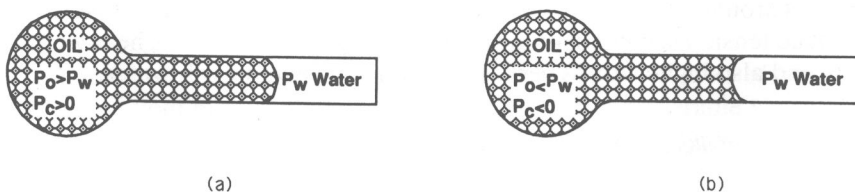


Figure 1.2. Diagrams illustrating variation of capillary pressure with wettability. (a) In preferentially water-wet container, capillary pressure in oil is positive. (b) In preferentially oil-wet container, capillary pressure in oil is negative.